OVERVIEW OF OIL SANDS DEVELOPMENT AND ITS ROLE IN MEETING CANADA'S ENERGY NEEDS

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Oil Sands

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by

Brahm D. Prasad and Harry O. Lillo

A B S T R A C T

While crude bitumen deposits have been discovered in several parts of the world, the largest deposits identified are those in Canada and Venezuela. It is a known fact that the initial in-place crude bitumen volumes in Alberta's oil sands deposits are of the same magnitude as the in-place crude oil volumes of the entire Middle East.

There are presently two commercial scale oil sands projects operating in Alberta - the Suncor and Syncrude mining operations. Two other commercial projects, those proposed by Alsands and Esso, are under review by the Alberta Government. Several other operators have expressed interest in constructing projects in the late 1980's. In addition, some 37 experimental schemes employing either mining or in situ recovery techniques are operating in the province. The current status of these projects is reviewed.

The Alberta Energy Resources Conservation Board regulates the energy industries in the province including oil sands operations. In reviewing applications for commercial and experimental oil sands schemes, it looks for maximum crude bitumen recovery and synthetic crude oil yield while ensuring orderly and efficient development. The Board makes information on operations and reserves available to the public and is in the process of modifying information release policies for experimental schemes.

In order that Canada achieves energy self sufficiency by 1990 or even by the year 2000, it will be necessary that every available resource be tapped to off-set this country's reliance on imported crude oil. Development of frontier and off-shore resources, which are still not

established reserves, will not detract from the need to continue developing established crude bitumen reserves. Oil sands could play a key role in reducing the gap between supply and demand in Canada.

INTRODUCTION

There are numerous oil sands deposits distributed around the globe. Both Canada and Venezuela have gigantic oil sands reserves. Canada's oil sands deposits located in the Province of Alberta represent over 1/3 of the world's known potential supply of bitumen resources. Canada is unique in this field in that it already has two commercial scale operations. Along with the development of oil sands comes the responsibility of assuring that the resource is developed at a rate that is both orderly and efficient. It is the responsibility of the Alberta Energy Resources Conservation Board (ERCB) as an agency appointed by the Alberta Government to regulate the development of the energy industries including oil sands. This paper deals with the current status of commercial and experimental schemes in oil sands. The ERCB role in processing and reviewing applications is also discussed. Global oil sands in-place volumes and Alberta's established bitumen reserves are also given. The relationship between rate of development and its role in meeting Canada's energy requirements is discussed at length.

1.0 OIL SANDS DEPOSITS OF THE WORLD

Because of the short-fall of conventional crude oil reserves in supplying the world's energy needs, it has become increasingly apparent that alternative sources of energy must be developed. Since it is still quite uncertain when oil reserves in frontier areas will be brought on-stream, the world has focused its attention on oil sands deposits as an immediate energy source.

It is known that a relatively small number of oil sands deposits contain in-place volumes of bitumen equivalent or greater than the world's total discovered in-place volumes of conventional crude oil [1] . For discussion, oil sands are defined as sands and other rock materials which contain heavy hydrocarbons chemically similar to conventional oils but which have high densities (low A.P.I. gravities) and high viscosities. These characteristics, until recently, have prevented the development of

oil sands deposits because of the complexities involved in recovering crude bitumen using conventional technology on a viable commercial scale.

The locations of some of the known world oil sands deposits are shown in Figure 1. Some characteristics including in-place volumes of the major deposits are given in Table 1. The figure and the table are an update of those published previously [2, 3] . By far the largest of these oil sands deposits are in Canada and Venezuela. Venezuela has a vast deposit in the Orinoco Oil Belt located in the southern part of the eastern Venezuela Basin. As yet the initial in-place volumes are still not proven but it has been estimated to exceed 318 x $10^9 m^3$ of oil [4] . Venezuela hopes to produce 20 000 m^3/d by 1988 and reach the goal of 159 000 m^3/d by the year 2000.

The most interesting deposit in the USSR is in north-eastern Siberia near Yarega. This deposit has the only commercial oil sands recovery operations in the USSR. The bitumen is being recovered by underground mining techniques coupled with steam stimulation. This operation has achieved a cumulative production of three million tonnes to date [5] . Very little information is available on in-place volumes from the USSR but it has been estimated that the Olenek deposit in Siberia contains enormous in-place volumes.

Deposits in the U.S.A. are concentrated in five states [6] - Utah, California, Kentucky, Texas, and New Mexico. By far the largest deposits are in Utah while Texas has relatively little oil sands resources. However, in relation to Canada and Venezuela, U. S. bitumen resources are considerably smaller and it would appear unlikely that they would contribute greatly to the country's energy needs. Other deposits have been found in Trinidad, Madagascar, Albania, Rumania, and Turkey with scattered deposits in many countries such as Peru [7] , Spain, Germany, Kuwait, India, Thailand, Senegal, and the Philippines.

The initial in-place crude bitumen volumes in Canada are considered to be approximately one third of the world's potential supply of energy resources [8] . The magnitude of Canada's oil sands deposits can be

appreciated when one realizes that they are comparable in size (as is the Venezuelan Orinoco Oil Belt) to the in-place volumes of conventional crude oil for the whole Middle East. Oil sands deposits have been discovered on the northern tip of Melville Island, however, the bulk of this country's deposits are in Alberta. It has been stated [1] that Alberta's Athabasca Deposit alone (excluding Cold Lake, Wabasca, Peace River, etc.), is the world's largest known accumulation of hydrocarbons and is at least four times as large as the largest of all giant oil fields, Ghawar, in Saudi Arabia.

A large portion of Alberta's oil sands deposits are contained within the lower cretaceous Mannville Group which has been subdivided into McMurray, Clearwater, and Grand Rapids' formations. The Peace River deposits occur in sands equivalent to the McMurray which are referred to as the Bluesky and Gething formations [9] . Table 1 includes in-place volumes [10] of Alberta's oil sands deposits including the Grosmont formation [11] of the Carbonate oil sands deposit and the remaining possible initial in-place volumes for the Carbonate oil sands deposit [9] . Their locations are shown in Figure 2.

2.0 ALBERTA'S BITUMEN RESERVES

2.1 Evaluation of Bitumen In-place Volumes

In-place bitumen volumes are typically evaluated using combined geophysical (electric, radioactive) log data and core analysis information. From this information, sand porosity and thickness, shale lens thickness, net pay and bitumen saturation by mass per cent are determined. Bitumen content below 3 mass per cent is considered a non-pay section and should an oil sands layer be less than 1.5 m thick within a continuous zone, it is considered non-pay as well. At each well, the equivalent thickness of bitumen column (i.e., bitumen-metres) is compiled in order to calculate in-place volumes. At the ERCB, the in-place volumes of crude bitumen are now determined by using a uniform square area (building block approach). In this procedure, the in-place bitumen volume of each square block of one-quarter township or 23 km^2 is evaluated [11] . Out of a total of 129 x $10^9 m^3$ of in-place initial volumes of bitumen (Table 1) in the Athabasca-McMurray deposit, 25 x $10^9 m^3$ falls within the surface mineable area.

2.2 Surface Mineable Bitumen Reserves Criteria

2.2.1 Minimum Bitumen Saturation and Oil Sands Zone Thickness

In the evaluation of mineable bitumen reserves, the ERCB currently uses a minimum bitumen saturation of 5 mass per cent and a minimum oil sands zone thickness of 1.5 m. The ERCB is presently reviewing these criteria. The minimum bitumen saturation cut-off in an ore zone should be determined on the basis of economic extraction recovery efficiencies as affected by feed quality and centre, and other reject materials. On the other hand, the minimum thickness cut-off for a pay zone should be based on the mining equipment and mining methods selected for the project. Generally, the minimum thickness cut-off is selected on the basis of an economic production rate; however, loss of ore must be minimized by the use of as thin a minimum thickness cut-off as is practical with the equipment selected.

Applicants [12, 13, 14], seeking ERCB approval of their projects have used a variety of criteria for evaluation of their applications. These criteria are presented in Table 2.

2.2.2 Economic Stripping Ratio

On the basis of its review of available data, the ERCB published the criteria in reports issued in 1974 [12] and 1975 [13] . These criteria were based on a modified form of a well established method for determining economically mineable reserves, known as the Break-Even Stripping Ratio, which is widely used in the mining industry. The ERCB further updated its evaluation in 1979 [14] using the same general approach as that employed in 1974 but incorporating recent economics and bitumen recovery data. The derivation and use of ERCB's Economic Stripping Ratio have been discussed at length in a previous paper [15] . Figure 3 shows the relationship between ESR and average plant feed bitumen saturations. Using a line similar to the middle line shown in Figure 3, a map of mineable oil sands in the Athabasca Wabiskaw-McMurray Deposit is presented as Figure 4.

2.2.3 Mineable and Established Reserves

Using the criteria discussed above, the potentially mineable reserves for those orebodies shown in Figure 4 have been calculated by the ERCB staff to be 12.4 x $10^9 m^3$ of crude bitumen. However, looking at technology demonstrated to date and accounting for the fact that environmental corridors, pipeline corridors, and some isolated small pockets of resources would not be recovered, and also considering the fact that current projects have caused the sterilization of some reserves due to the placement of surface facilities, the ERCB has estimated the established bitumen reserves to be 5.3 x $10^9 m^3$ or approximately 43% of the potentially mineable reserves. This quantity of crude bitumen, when upgraded, would yield approximately 4.0 x $10^9 m^3$ of synthetic crude oil [10].

2.3 In Situ Reserves

No established reserves have yet been assigned by the ERCB to deposits from which bitumen would be recovered by in situ techniques [10]. A number of problems have prevented the determination of established in situ reserves. To date there has been no commercial production from an in situ oil sands scheme, hence, it is difficult to establish a recovery level. Additional difficulties include suitability of different in situ recovery techniques when applying them to various reservoir types and variability in the actual reservoirs. It is hoped that established reserves for in situ areas would be published before the end of the decade.

3.0 CURRENT STATUS OF OIL SANDS DEVELOPMENT IN ALBERTA

3.1 Commercial Schemes

The current status of oil sands commercial schemes in Alberta has been summarized in Table 3 [14, 16, 17, 18, 19]. The locations of Suncor, Syncrude and Alsands project areas are shown in Figure 4. Figure 4 also shows the proposed location of a new town that will initially accommodate Alsands' employees and their families, and later it will also accommodate the labour forces for other oil sands projects in the area.

The Esso scheme will be Canada's first commercial scale in situ bitumen recovery project located in the Cold Lake area. The recovery technique proposed by Esso is that of in situ steam stimulation or "huff and puff". This process involves injecting unsaturated steam into the 460 m deep reservoir at greater than formation fracture pressures for a period of time. The energy released heats the reservoir and creates a less viscous bitumen/water emulsion which can then be pumped to the surface by conventional oil field techniques. Production would initially take place through blowdown of the reservoir pressure, and subsequently, by pumping the well. When production declines, the entire stimulation cycle is repeated. The project will utilize 8000 wells over the life of the project with 2000 operating at any time [19].

In addition to the two operating projects (Suncor and Syncrude), and two other proposed projects (Alsands and Esso), several other companies have made public announcements concerning possible oil sands schemes.

3.1.1 Petro-Canada and AGTL Project

Petro-Canada and Alberta Gas Trunk Lines Co. Ltd. (AGTL) have recently announced that they will jointly construct an oil sands mining project on a scale similar to Syncrude and Alsands with a production rate of up to 24 000 m^3/d of synthetic crude oil. Although no specific project site has yet been selected, the plant will be constructed in the Athabasca oil sands deposit. Petro-Canada and AGTL plan to submit a formal application to the ERCB by late 1982. It is believed that Petro-Canada and AGTL will share the leadership, management, and ownership of the project equally. Other companies may later join the venture. The companies plan to offer Alberta Indians the right to acquire up to 10 per cent of the project. Husky Oil Ltd. may be given a specific option to take up to 10 per cent of the project. Petro-Canada has emphasized its commitment to carry out research in the early stages of the project in the hope of developing new technology for more efficient operations.

3.1.2 Gulf Project

Gulf Canada Resources Inc. has recently announced that it is studying the possibility of constructing an oil sands mining project at the lease now held by Home Oil Company Ltd. (87.5%) and Alminex Ltd. (12.5%). It is believed that Gulf will acquire an 83.75 per cent interest in the Home-Alminex lease located in Township 94, south of Alsands proposed project area (Figure 4), 43 km north of Fort McMurray. Gulf is currently carrying out an exploration drilling program on the lease to determine the quality of the oil sands. After evaluation of its exploration feasibility programs, Gulf plans to submit an application to the ERCB for construction of an oil sands mining project.

3.1.3 Other Projects

The authors believe that there are several other companies who are directly or indirectly involved in carrying out feasibility studies to construct projects of either the mining or in situ type in Alberta oil sands deposits. However, it is expected to be some time before any companies make public announcements of their plans.

3.2 Experimental Schemes

An "experimental scheme" can probably best be described as a scheme or operation utilizing methods that may be untried or unproven in a particular application and is not designed for commercial viability, including but not limited to, test and pilot schemes.

Experimental scheme approvals cover mining, in situ and hybrid (combined mining and in situ) recovery methods as well as bitumen extraction and upgrading processes, normally when the technique is being tested at a field scale. Although the majority of the experimental schemes in Alberta employ different methods of in situ recovery techniques, there are some active mining, extraction, and hybrid experimental schemes.

There were some 37 active approved experimental schemes in Alberta as of July 1980. A list of active experimental projects is shown on Table 4 and a map showing the location of these schemes is shown as Figure 5. Tables 5 and 6 show the relative status of some of the experimental schemes. These tables were published by AOSTRA [20] .

Most of the in situ experimental schemes employ steam or air injection to create heat which reduces the viscosity of the bitumen or heavy oil so it may be pumped to surface by conventional techniques. The scale of these experimental schemes ranges from Esso's Leming experiment which is expected to produce some 2200 m^3/d down to single well tests which may produce as little as 1 m^3/d.

One interesting hybrid technology being developed is that of Mine Assisted In Situ Processing (MAISP). The essential thrust of MAISP is to achieve more efficient in situ production from oil sands reservoirs by placing the production facilities at or near the producing formation through conventional mining techniques. An underground mine system could be developed through vertical shafts and a tunnel layout to provide access for men, equipment, steam and production lines (Figure 6). Drilling chambers in the tunnel system below the producing formation would permit the drilling of a series of relatively short inclined drill holes into the producing formation. In addition to having a higher density of wells in the formation which promote easier heating and well communication, this layout would minimize heat loss to the non productive overburden formation.

Haston [21] and Quinn [22] both believe that a MAISP operation would be feasible for the Athabasca Deposit and that the economics could be viable for such an operation.

Petro-Canada is presently experimenting with the MAISP concept at the Mildred Lake Project site. The company is testing the feasibility of horizontal drilling and completion through a surface demonstration test in the Athabasca River Valley. Three horizontal wells have been drilled, from the limestone into the McMurray Formation. The wells have been completed and steaming is underway.

AOSTRA and Gulf are working toward development of a MAISP type operation in the Surmont Area southeast of Ft. McMurray. The test will include an engineering analysis and a field test which is expected to cost in the order of $90 million. The concepts to be evaluated will involved vertical shafts, horizontal tunnels, and horizontal wells.

3.2.1 Experimental Schemes - Act and Regulations

The present Oil and Gas Conservation Act makes provision for two types of oil sands operation - commercial and experimental. The distinction between a major commercial operation and a small, truly experimental scheme is obvious. The decision to allow a prototype or moderate scale pilot operation utilizing a somewhat proven technology but of questionable economic viability to be classified as an experimental scheme is more difficult. These schemes operating under experimental status are afforded special tax advantages and reduced royalties by Federal and Provincial Government bodies respectively. It can be anticipated that many of the truly experimental operations in existence today will be scaling-up to prototype or semi-commercial operations. Only with the tax and royalty incentives would these operations be considered economically viable. The question as to whether such operations should be considered experimental or commercial will have to be faced by government, industry, and the ERCB in the next few years. The answer is not readily apparent at this time.

Once it has been determined that a proposal falls into the category of an experimental scheme, a full review is undertaken by ERCB staff and the application is also referred to the Department of the Environment for its comments. To date no experimental scheme applications have been advertised nor have any gone to public hearing. In the absence of public review, particular attention must be paid to any potential impact on local inhabitants, or other mineral or property owners. In keeping with a procedure established some 12 months ago, the ERCB does make the experimental scheme applications public after approval is granted. Under present policies, all experimental scheme information

received subsequent to the application is held confidential until five years after commercial operations have commenced. ERCB policy on release of confidential information and requests for information by concerned local interests is being reviewed. It is most likely more experimental scheme information will be made public in the future.

4.0 ERCB ROLE IN DEVELOPMENT

4.1 Commercial Scheme Applications

It is the responsibility of the ERCB to maintain surveillance over the province's production of its energy resources. This entails not only day-to-day monitoring of operations but also requires establishment of long term goals in meeting energy supplies both in a provincial and national context in balance with conservation and environmental constraints. Under section 43 of The Oil and Gas Conservation Act of Alberta, before commencing any commercial operation in oil sands, applicants are required to submit a formal application to the ERCB for approval of their schemes. Upon receipt of the application, the ERCB calls a public hearing [23] to provide it with the necessary information to make an appropriate decision. The ERCB staff conducts a detailed evaluation of the application. After the hearing, the ERCB makes its recommendation to the Alberta Government as to whether the application should be approved or denied.

Over the past two decades, the approvals for any oil sands schemes have been granted under The Oil and Gas Conservation Act and specific conditions were included in the approvals. Rapid development of bitumen resources projects in the province has necessitated a separate act dealing speficically with bitumen resource matters. Therefore The Oil Sands Conservation Act has been drafted to eventually replace The Oil and Gas Conservation Act in dealing with oil sands matters.

4.2 Concerns in Reviewing Surface Mining Applications

In assessing any application for an oil sands surface mining scheme, the ERCB reviews the following areas of major concerns:

4.2.1 Mineable Oil Sands Limits

While the oil sands of Alberta's Athabasca Wabiskaw-McMurray Deposit are relatively continuous and demonstrate a certain amount of uniformity, it is essential to delineate limits of economically surface mineable oil sands to avoid sterilization of bitumen reserves when siting surface facilities. Variations in bitumen saturation, and in the thickness of mineable oil sands and discard (overburden and reject), occur throughout the oil sands deposit. Methods of determination of mineable oil sands limits have been discussed earlier in this paper. Since surface mineable limits depend on the oil price at the time of mining the ore bodies, on capital and operating costs, on the royalties and taxes, and on extraction recovery efficiencies, the economic stripping ratio for the orebodies must be periodically up-dated as new information becomes available.

4.2.2 Surface Facility Locations

The importance of locating surface facilities, such as processing plants, tailings ponds, and discard sites, on non-mineable areas has been dealt with in previous papers [15, 24, 27] . Table 7 dramatically illustrates that the possible number of projects, similar in size to Syncrude and Alsands, could be reduded from 36 to 15 if such facilities are not located properly. To avoid the sterilization of mineable reserves, caution must be taken in locating such facilities not only because of increased demand for energy but because of the high cost associated with later removing surface facilities to recover the underlying resources. There are short term economic benefits in locating any surface facilities adjacent to the mine. However, in the long term, it will be of most benefit to the lease holders if they leave the mineable areas accessible for future mining. In this way, they could either expand their mine life and thus the project life, or they could sublease or trade part of the lease to other leaseholders with substantial economic return. With careful and proper long term planning, substantial mineable reserves could be added to Alberta's existing established reserves. Effort must also be directed toward reducing the size of out-of-pit tailings ponds, possibly by modified dike

construction techniques. Anhydrous extraction processes, if commercialized, would also alleviate this problem by permitting tailings to be returned to the mined out pit much earlier in the life of a project.

4.2.3 Mining Systems and Mine Plans

Selection of mining equipment and mining methods play a critical role in meeting the desired level of productivity and efficient recovery. Several mining systems are feasible but because of the size of the operation, economics has favoured the use of large mining equipment and high speed conveyors. Furthermore, the relatively low unit value of oil sands as ore requires that vast quantities of ore be mined. This necessitates the development of large equipment in order to maintain a steady rate of plant feed material. The nature of the oil sands itself causes problems because it requires very large cutting forces and is extremely abrasive to the cutting edge. Long winters at temperatures as low as $-50^{\circ}C$ also effect equipment selection.

The two main systems in use, the bucket wheel excavator, and the dragline both have advantages and disadvantages. Each project must be assessed individually and the mining system selected should be based on the total mining depth, the composition of overburden and oil sands, structural geology, aquifers and foundation materials. It is required that the mining system selected results in the practical maximum recovery of bitumen within the area to be mined. Considerable research is still required in the area of mining equipment selection and in conjunction with this there should be much more long and short range planning carried out in sufficient detail to balance the disposition of overburden, reject and plant feed materials. It is imperative that long range mine planning for a project be commenced several years in advance in order to ensure that the decisions in selecting the appropriate type of mining system and equipment will not be delayed. It is becoming more apparent that pre-stripping of overburden in advance of mining the plant feed material is in the long run more economical and efficient since it minimizes dilution of the plant feed material and thus improves the extraction recovery.

4.2.4 Geological, Geotechnical and Hydrological Data

In order to define the limits of the orebody, it is necessary that sufficient drilling be carried out. Information taken from drilling data should be used to gather geotechnical and hydrological information where practical. In selecting the appropriate mining system, information on overburden depth, ore zone depth, and composition of material is drawn from drilling data as well. The major concern is that drilling data be of sufficient detail to ensure that the observations drawn from the data are representative of the entire area concerned.

4.2.5 Mining at Lease Boundary

In order to maximize the recovery of oil sands or crude bitumen, the ERCB requires that operators prepare a scheme to recover the mineable oil sands adjacent to and underlying the lease boundary lines. The ERCB encourages the operators to work out a scheme that is mutually acceptable and meets the ERCB approval. In such cases, some sort of compensation may have to be paid to one or other of the lease holders.

4.2.6 In-Pit Tailings Disposal

Any tailings or discard disposal in the mined-out pit must be carried out in an orderly fashion so that sterilization of mineable oil sands in and adjacent to the mined-out face should not take place.

4.3 Concerns in Reviewing In Situ Applications

In the review of an application, all aspects of a project are considered including technical, cost/benefit, social impact, and environmental matters. Although the ERCB and its staff consider each aspect separately, the authors have only dealt with the technical considerations in this paper. While the emphasis may shift from application to application, the major areas of concern to the ERCB are expected to be:

4.3.1 The Adequacy of Recovery

Unlike mining projects where all the ore exploited is physically removed and processed, the in situ operations only mobilize and recover a portion of the bitumen in-place. With present proven technologies, this recovery is in the order of 20 per cent. This recovery factor could be increased by implementation of follow-up recovery techniques which would utilize the communication paths gained through the initial operations. Operations modified to take advantage of gravity drainage might also extend producing well life and push the recovery efficiency beyond the 30 per cent level [11].

4.3.2 Water Supply and Disposal

In situ recovery operations utilizing steam are very water intensive. Typically such an operation would utilize 6 to 7 m^3 of water for each 1 m^3 synthetic crude oil produced. About 60 per cent of this would be fresh make-up water with the remainder being recycled water and that portion of the water not recycled must be disposed of. Waste waters meeting Alberta's waste water effluent guidelines may be discharged to surface waters. Aqueous wastes high in dissolved solids are normally disposed of to subsurface formations via deep disposal wells.

4.3.3 Make-up or Balancing Fuels

The majority of the fuel requirement for in situ operations may be generated internally. However, there is a requirement for external fuels amounting to approximately 20 per cent of the total fuel requirements. Esso had originally proposed to use coal as its make-up fuel thus combining a dimension of mining with in situ recovery operations.

4.3.4 Geology and In-place Volumes of Crude Bitumen

Like any other ore body, sufficient definition of the resource must be made in order to evaluate the project and its economic and technical

viability. Interpretation of logs and cores are a necessary part of the review of any application.

4.3.5 Utility and Upgrading Operations

The Board considers it important that efficient methods are employed to convert bitumen to synthetic crude. Likewise, the most energy efficient methods are expected to be employed to raise steam that would be used throughout the project.

4.3.6 Site Development Plan

Unlike mining operations where location of surface facilities can sterilize mineable reserves, in situ operations can take place below such facilities through the use of deviated or directionally drilled wells. The layout of surface facilities becomes more a question of environmental than technical consideration.

4.3.7 Well Drilling and Downhole Installations

The well drilling, casing, cementing, completion, and downhole equipment are matters of considerable interest to the ERCB. These practices must be of sound technical nature and normally proven in field operations before an approval is granted.

4.3.8 Material and Energy Balances

The ERCB critically reviews all conversion efficiencies, energy efficiencies and must be assured that they are in accordance with good conservation, engineering, and environmental practices [11] .

5.0 FACTORS AFFECTING MINEABLE RESERVES

5.1 Crude Oil Price

The crude oil price is a critical factor in determining mineable reserves. For example, using the graph shown in Figure 3, the potential mineable

reserves would be reduced from 12.4 x $10^9 m^3$ for the $\$200/m^3$ case to 7.5 x $10^9 m^3$ for the $\$160/m^3$ case [15].

5.2 Project Financing

The project could be financed using either equity financing, where the large portion of capital raised for the project comes out of the company's retained earnings, or utility financing, where the project's viability is guaranteed. In the equity case, the company expects to receive a return on investment commensurate with the return it could receive if the money was invested in some other available alternative. In the utility or government guaranteed case, the risk of the project is decreased because of these guarantees and this enables the proponent to secure a substantial amount of debt financing. For the economic stripping ratio calculation in the graph shown in Figure 3, we assumed a 70/30 debt/equity ratio; 3 per cent real interest cost on debt, and 15 per cent real return on equity. If utility financing is used, the cost of capital would decrease significantly. For example, using the case in Figure 3, this cost has been reduced from $\$87.74\ \$/m^3$ to $\$51.02/m^3$ of synthetic crude oil [11, 15]. This amount saved in capital expenditure can be applied to costs of mining higher ratio (discard to ore) ores, thus increasing the potential mineable reserves.

5.3 Royalties and Taxes

It is obvious that increasing or decreasing royalties and taxes will have the effect of reducing or expanding the mineable reserves.

5.4 Environmental Constraints

Increasingly environmental constraints are of importance in oil sands development because of disturbance to the natural environment. Severe environmental constraints may seriously alter the economics of any project since the ultimate costs per m^3 of oil will be significantly increased. However, the need to protect the environment should not be minimized.

For example, environmental constraints in the surface mining area include possible water consumption limits in relation to Athabasca River flow rates, cumulative air-shed and surface water shed contaminant acceptance levels, possible restrictions on cumulative exposed mine pit land disturbance areas, achievable land reclamation rates and tolerance/maintenance philosophy respecting tailings sludge accumulations. These environmental considerations may limit the rate of production to the point that possibly no more than five projects would simultaneously be in operation [24]. Strict environmental regulations may cause development of many deposits to be postponed, cancelled or severely reduced. Thus it would seem that trade-offs may have to be made to accommodate the nation's energy demands against the need to avoid long term detrimental effects to the environment.

5.5 Other Factors

As discussed previously, such factors as surface facility locations, mining systems, mining at lease boundaries, and in-pit tailings disposal will also have an effect on the mineable reserves.

6.0 RATE OF DEVELOPMENT

The pace of development will be determined by a number of complex factors. Firstly, a project will require approximately a 10-year period from the project definition phase until plant start up. This includes the one to two years for approval, approximately one and a half years for process design and preparation of a detailed estimate, and approximately a three-year detailed engineering period which would overlap a five-year plant construction period. Start-up operations would likely be conducted over at least a one year period. One of the major constraints will be the recruiting and training of skilled labour on a massive scale. A total construction labour force of 5000 on an average is required over a five year period with peak labour forces amounting to from 8000 to 10000 people. Following the construction stage, operating staff would amount to from 2500 to 3000 per project [11]. The construction material and equipment will also be massive by nature and therefore will require extensive lead time.

Capital requirements for projects on a mega scale such as these will be in the range of 5-6 billion dollars depending upon start-up construction dates.

Crude oil price, amount of royalties and taxes paid, rate of return on capital investment, and political climate will have a bearing on the amount of incentive the operator has to develop a project. In order to avoid adverse social and economic pressures, development must be controlled by sequential building of projects. In addition, technological and environmental obstacles for both surface and in situ production of bitumen are manifold and will continue to hinder rate of development and add a heavy cost burden until solved by further research.

Based on the above constraints, Table 8 shows the proposed rate of oil sands development for crude as forecasted by the Canadian Petroleum Association in its submission to the ERCB [25] .

7.0 ROLE OF OIL SANDS IN MEETING CANADA'S ENERGY NEEDS

If Canada is to achieve its goal of energy self-sufficiency by 1990 or even by the year 2000, it must tap every available source of energy to off-set its reliance on imported crude oil. Canada may eventually reach this goal considering the magnitude of its oil sands and frontier oil reserves. However, development of frontier and off-shore reserves can not be considered to be of sufficient magnitude in the near future since reserves have not as yet been established in sufficiently large quantities, and enormous technological problems are still to be overcome in processing and transporting this resource.

Based on the 7-8 year lead time required, it can be projected that the start-up time for production of hydrocarbons from frontier areas may be 1988 with a production rate of 16 000 m^3/d, it can also be assumed that production of hydrocarbons from frontier areas by the year 2000 will not be greater than 80 000m^3/d.

In the face of dwindling conventional crude oil supplies, it is the authors' opinion that Canada must now consider tapping its oil sands reserves in order to fill the ever increasing gap between supply and demand. However, the graph presented in Figure 7 based on Table 8 illustrates that even with the development of oil sands and frontier areas, Canada can not completely fulfill its energy needs at this rate of development. In fact, based on the National Energy Board's prediction of demands for crude oil shown in the graph [26] , the gap between total supply and demand grows ever wider each year.

Canada is not only concerned with closing the gap between supply and demand but also in reducing crude oil imports. By increasing domestic energy supplies through oil sands development, now, the nation can reduce its deficit dramatically. Referring to the graph, one can see that by the year 2000, there may have to be approximately 160 x $10^3 m^3/d$ import of crude oil in order to meet total Canadian energy requirements.

Assuming a current world crude oil price of $\$220/m^3$, Canada would increase her national deficit by 12-13 x 10^9 dollars/year (1980 dollars) by the year 2000, should she continue to import crude oil to fill the gap. However, should Canada pour this capital into rapid development of oil sands and other energy sources in Canada, this would help create a much more stable economic climate and directly stimulate the economy by creating new employment for many Canadians and increasing royalties and taxes paid to the governments. To ensure expeditious development of such high risk projects, it will be necessary to develop a long term energy policy that will encourage a stable economic and political climate.

The gap between supply and demand could be narrowed bringing the goal of self sufficiency closer <u>if</u> development of oil sands and possibly frontier oil (and any other form of energy) proceeds at a much faster rate than shown in the graph. The authors believe that oil sands will play a significant role in meeting Canada's energy needs but self-sufficiency can only be achieved if the government and private sector cooperate to meet this goal.

8.0 CONCLUSIONS

The world has vast quantities of initial in-place crude bitumen volumes. Potential reserves (for both mining and in situ operations) in Canada could be substantially increased if favourable economic incentives were adopted. Location of surface facilities and type of mining system selected must also be thoroughly evaluated in relation to their effect on mineable reserves. Similarly, the recovery efficiency and water balances have a significant effect on the in situ reserves.

In developing oil sands, there are many uncertainties. The sheer magnitude of the projects present problems of manpower and equipment on scales that are staggering. But over and above this, is the problem of financing such massive projects.

In spite of innumerable difficulties, two commercial oil sands mining projects are on stream with several other projects being considered for development. Rapid development of oil sands and other energy sources in Canada is necessary if the nation wishes to reduce or eliminate her deficit paid on imported oil. A long term energy policy may be necessary to promote rational development of all resources. Compromises may have to be made between the energy and economic demands of the nation and the social and environmental consequences of oil sands development as with other resources.

In conclusion, we would like to emphasize that any opinion expressed in this paper is that of the authors and not necessarily that of the ERCB.

ACKNOWLEDGEMENTS

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TABLE I

MAJOR OIL SANDS DEPOSITS OF THE WORLD

COUNTRY	DEPOSIT (LOCATION)	AGE OF RESERVOIR ROCK	AREAL EXTENT (10^3 ha)	AVERAGE PAY THICKNESS (m)	BITUMEN SATURATION (% MASS)	CHARACTER OF OIL DENSITY (kg/m³)	CHARACTER OF OIL (% SULPHUR)	OVERBURDEN THICKNESS (m)	INITIAL VOLUME IN PLACE (10^6m³)
CANADA	Athabasca (Alta.) **		4121	22	9.4 Av.	1010 Av.	4-5	0-750	129 000
	Buffalo Head Hills (Alta.)		185	4	6.1 Av.	1010 Av.	4-5	300-700	920
	Cold Lake (Alta.)	L. Cretaceous	2135	16*	6.7 Av.	1000 Av.	4-5	300-600	28 270
	Peace River (Alta.)		786	15	4.5 Av.	1010 Av.	4-5	300-750	11 400
	Wabasca (Alta.)		689	20*	5.3 Av.	1014 Av.	4-5	150-450	6 770
	Grosmont, Carbonate (Alta.)	Paleozoic	350	6*				224-468	10 000
	Other Carbonate -Possible	Paleozoic							157 000
	TOTAL ALBERTA OIL SANDS								363 360
	Melville Island (N.W.T.)	Triassic	10	21	<16	1000 Av.	.9-2.2	0-610	8
Eastern Venezuela	Orinoco Oil Belt	Oligocene	1699	30	10	950-1010	2-4	0-914m	317 965
	Guanoco	Recent Alluvium	.5	5	64	1010 Av.	5.9	Nil	9.86
U.S.S.R.	Olenek (Siberia)	-	-	-	-	-	-	-	95 390
	Cheildag (Kobystan)	M. Miocene	.03	61	5-13	-	-	Shallow	3.8
U. S. A.	Tar Sand Triangle (Utah)	-	-	-	-	-	-	-	1 987
	Peor Springs (Utah)	U. Eocene	.7	10	9	-	4.4	Shallow	635
	Sunnyside (Utah)	U. Eocene	14	55	9	-	.8	0-55	556
	Asphalt Ridge (Utah)	Oligocene & U. Cretaceous	4.5	30	11	900-1010	.5	0-610	190
	Edna (California)	Mid-Pliocene	2.6	76	9-16	990-1010	.5	0-182	27.8
	Uvalde (Texas)	-	-	-	-	<980	4.2	-	19.7
	Sisquoc (California)	U. Pliocene	.7	25.9	14-18	-	-	4.5-21.3	16.8
	Casmalia (California)	-	-	-	-	1010-1040	-	-	14
	Whiterocks (Utah)	Jurassic	.8	290	10	-	-	Nil	10.3
						990 Av.	.5		
	OTHERS (U.S.A.)	-	-	-	-	-	-	-	340.8
TRINIDAD	La Brea	U. Miocene	.05	41	54	970-1009	6-8	76	319
MADAGASCAR	Bemolanga	Trias	30	10	6-9	1010 Av.	.7	10	278
ALBANIA	Selenizza	Mio-Pliocene	2.1	15.2	8-14	980-1060	6.1	Shallow	50
PERU	Chumpi	Vivian-	-	-	-	1000-1030	-	-	10.5
RUMANIA	Derna	Cretaceous Pliocene	.3	4.5	15-22	-	.7	Shallow	5

* Arithmetic total of all formations.

** Athabasca Wabiskaw - McMurray Deposit

TABLE 2

MINIMUM BITUMEN SATURATION AND MINIMUM THICKNESS CUT-OFF

APPLICANT	MINIMUM SATURATION CUT-OFF (MASS PER CENT)	MINING SYSTEM	MINIMUM THICKNESS CUT-OFF (m)
Suncor	8	Bucket Wheel Excavator (BWE)	None
Syncrude	6	Dragline (D/L)	Under study
Petrofina	6	BWE	6*
Home	6	BWE	1.5*
Alsands	**	D/L	4.5

* Minimum one half hour reject production is necessary.

** Alsands based cut-off on an economic computer model utilizing 0.25 m intervals.

TABLE 3

CURRENT STATUS OF OIL SANDS COMMERCIAL SCHEMES

	SUNCOR [1]	SYNCRUDE	ALSANDS (PROPOSED)	ESSO (PROPOSED)
Commencement of Production	1967	1977	1986	1986
Recovery Method	Surface Mining Bucket Wheel Excavators	Surface Mining Draglines - Bucket Wheel Reclaimers [2]	Surface Mining Draglines - Bucket Wheel Reclaimers [3]	In Situ Recovery Cyclic steam stimulation ("Huff and Puff")
Extraction Process	Hot Water	Hot Water	Hot Water	-
Upgrading Process	Delayed Coking & Hydro-treating	Fluid Coking & Hydrocon-version	Fluid Coking	Flexicoking
Approved Production Rate of Synthetic Crude (m^3/d)	10 330	20 600	22 250	22 300

1. Suncor is in the process of expanding and modifying its existing facilities.
2. Currently prestripping of overburden is being carried out by use of additional mobile equipment.
3. Alsands is carrying out extensive work to select appropriate mining equipment and mining system.

TABLE 4

Active Projects
Alberta Oil Sands Deposits

Approval No.	Effective Date	Expires	Operator	Formation	Field or Area	Location
	ATHABASCA					
	Commercial					
2821 A (1944 & 540)	73 12 12		Suncor	Wabiskaw-McMurray	Mildred Lake	92-10 W4M
2959 (1920 & 1725)	73 10 03	04 12 31	Syncrude	Wabiskaw-McMurray	Mildred Lake	92-10 W4M
	Experimental					
3070 (1769F)	80 05 02	84 12 31	Texaco	Wabiskaw-McMurray	McMurray	15-88-8 W4M
1942A	73 11 14	80 12 31	Amoco	Wabiskaw-McMurray	Gregoire Lake	27-85-8 W4M
2235	76 03 18	82 03 31	World Oil Mining	Wabiskaw-McMurray		
2687	78 05 31	81 04 30	RTR Oil Sands	Wabiskaw-McMurray	Mildred Lake	26-92-10-W4M
2749	78 11 16	81 11 01	Petro-Canada	Wabiskaw-McMurray	Mildred Lake	34-92-10 W4M
3015A (2782A)	79 01 16	80 12 31	Gulf	Wabiskaw-McMurray	Pelican	28-79-21 W4M
3011	80 01 10	83 01 31	Gulf	Wabiskaw-McMurray	Desmarais	8-81-22 W4M
3083	80 06 05	81 06 30	Home	Wabiskaw-McMurray	Leismer	7-77-7 W4M
2850A	79 01 16	84 04 30	Petro-Canada	Wabiskaw-McMurray	Surmont	26-85-9 W4M
3006	80 01 17	81 01 31	Petro-Canada	Wabiskaw-McMurray	Primrose	29-73-7 W4M
3035	80 02 14	84 01 31	CDC/Tenneco Oil	Wabiskaw-McMurray	Kearl Lake	10-95-7 W4M
3009	80 01 21	86 12 31	General American	Wabiskaw-McMurray	Jolf Fou	30-81-19 W4M
3099	80 06 26	83 06 30	Gulf	Wabiskaw-McMurray	Surmont	20-83-6 W4M 24-83-7 W4M
	COLD LAKE					
	Experimental					
2483A (713 & 904)	64 12 02	82 12 31	Esso	Clearwater	Ethel Lake	22-64-3 W4M
2484A (857 & 905)	66 06 01	81 12 31	Esso	Clearwater	Ethel Lake	22-64-3 W4M

TABLE 4 (CONT'D)

1503E	71 04 13	81 04 30	Esso	Clearwater	May	27-64-3 W4M
1954A	74 01 29	81 12 31	Murphy Oil	Lower Grand Rapids	Lindbergh	13-58-5 W4M
1965B	74 02 11	80 12 31	Union Texas	Clearwater	Ardmore	20-62-3 W4M
2138B	75 06 25	82 05 31	Norcen	Clearwater	Primrose	6-66-1 W4M
2298B	76 08 19	83 08 31	Suncor/WECO	Upper Grand Rapids	Fort Kent	28-61-4 W4M
2323	76 10 20	81 10 31	Gulf	Clearwater	Cold Lake	12-65-2 W4M
2337B	76 11 19	81 11 30	BP	Clearwater	Marguerite Lake	7-66-5 W4M
2269A	77 04 18	81 06 30	Chevron	Lower Grand Rapids	Beaver Crossing	31-61-1 W4M
2943A (1951 & 2577)	73 12 73	84 12 31	Esso	Clearwater	Leming/Bourque	4-65-3 W4M
2928	79 08 27	82 07 31	Petro-Canada	Lower Grand Rapids	Muriel Lake	22-59-4 W4M
2992	90 01 08	81 01 81	Amoco	Upper Grand Rapids	St. Lina	4-63-8 W4M
	PEACE RIVER					
	Experimental					
2485	77 06 24	82 06 30	Shell	Bluesky-Bullhead	Cadotte Lake	21-85-15 W5M
OTHER DEPOSITS, FIELDS OR AREAS						
	Experimental					
2057D	74 09 16	80 09 30	Norcen	Upper Mannville B	Provost	17-37-1 W4M
2062A	74 10 31	81 12 31	Union	Grosmont	Chipewyan	21-89-21 W4M
2142A	75 07 08	80 12 31	Mobil/ General Crude	Sparky Q	Lloydminster	12-49-1 W4M
2144A	75 07 16	81 06 31	Mobil/ General Crude	Sparky K	Lloydminster	18-51-2 W4M
2367C	77-01-17	81 12 31	Union	Grosmont	Buffalo Creek	5-88-19 W4M
2531A	77 09 07	80 08 31	Husky	Sparky C	Lloydminster	30-50-1 W4M
2768	78 12 15	83 12 31	Petro-Canada	Wainwright D	Viking-Kinsella	30-48-8 W4M
3002A	80 01 08	80 11 30	Dome	Lloydminster A	Morgan	35-51-4 W4M
3105	80 06 26	83 06 30	Dome	Lloydminster A	Morgan	35-51-4 W4M
3086	80 06 05	85 06 01	Alberta Energy	Upper Mannville J	Suffield	10-20-8 W4M

TABLE 5

EXPERIMENTAL PROJECTS IN OIL SAND DEPOSITS IN ALBERTA (AFTER AOSTRA [20])

DEPOSIT	PROCESS	OPERATOR	NO. OF WELLS	EXPECTED GROSS COST** $ M	START/COMPLETION DATE
ATHABASCA					
Fort McMurray	Steam	Texaco Expl. Canada	52	25	72/80
*Gregoire Lake	Steam/Combustion	Amoco Canada	25	71	73/80
*Surmont	Fracturing	Numac Oil & Gas	1	2	74/80
Mildred Lake	Horizontal Drill.	Petro-Canada	3	5	79/80
NW of Gregoire Lk	Electric/Steam	Petro-Canada	4	35	80/84
COLD LAKE					
Ethel Lake	Steam	Esso Resources	42	5	64/80
May	Steam	Esso Resources	30	10	71/81
Leming	Steam	Esso Resources	82	30	73/--
Ardmore	Steam	Union Texas	15	4	74/80
Primrose Lake	Steam	Norcen	9	14	75/80
Fort Kent	Steam	Worldwide Energy	31	4	76/83
Cold Lake	Steam	Gulf Canada	6	7	76/81
*Marguerite Lake	Steam/Combustion	BP Exploration	17	31	76/81
Beaver Crossing	Steam	Chevron Standard	7	7	77/81
Bourque	Steam	Esso Resources	12	4	77/82
Primrose	Steam	Petro-Canada	1	--	79/79
Muriel Lake	Steam	Worldwide Energy	7	6	80/--
PEACE RIVER					
*Cadotte Lake	Steam	Shell Canada Resources	31	125	77/84
WABASCA					
Wood River	Steam/Combustion	Gulf Canada	34	20	74/79
Pelican	Steam	Gulf Canada	3	2	79/79
CARBONATE					
*Buffalo Creek	Steam/Combustion	Union Oil	5	10	77/81
*Chipewyan	Steam	Union Oil	7	3	74/79

* Projects having AOSTRA participation.
** Estimated gross costs for pilot and associated research in period defined by start/completion dates. These costs do not include lease costs or royalties.

TABLE 6

EXPERIMENTAL PROJECTS IN HEAVY OIL DEPOSITS IN ALBERTA (AFTER AOSTRA [20])

DEPOSIT	PROCESS	OPERATOR	NO. OF WELLS	EXPECTED GROSS COST ** $ M	START/COMPLETION DATES
Lindberg	Steam	Murphy Oil	7	3	74/81
Provost	Combustion	Tesoro Petroleum Corp.	9	--	74/80
Lloydminster	Combustion	General Crude	97	10	75/80
Lloydminster	Combustion	General Crude	46	7	75/80
Lloydminster	Steam	Husky Oil	3	2	77/79
Provost	Steam	Tesoro Petroleum Corp.	1	--	78/79
Viking-Kinsela*	Combustion	Petro-Canada	24	16	78/83

* Projects having AOSTRA participation.
** Estimated gross costs for pilot and associated research in period defined by start/completion dates. These costs do not include lease costs or royalties.

TABLE 7

IMPACT OF SURFACE FACILITY LOCATIONS

Total Mineable Area as per Figure 4 (within Athabasca Deposit)	1300 km^2
Minus Environmental Corridors, Pipelines Highways, etc.	-200 km^2
Remaining Mineable Area	1100 km^2
Mine Area Required/Project	30 km^2
Area Required for Surface Facilities/Project	40 km^2
Possible Number of Projects $= \frac{1100}{30} =$	36 *
$= \frac{1100}{70} =$	15 **

* If surface facilities not located on mineable area

* * If surface facilities located on mineable area

TABLE 8

SYNTHETIC CRUDE OIL PRODUCTION FORECAST (AFTER CPA[25])

(OIL SANDS)

$10^3 m^3/d$

YEAR	1980	81	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	2000
SUNCOR	7	7	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
SYNCRUDE	11	13	17	20	20	20	20	22	28	30	30	30	30	30	30	30	30	30	30	30	30
ESSO							1	9	17	22	22	22	22	22	22	22	22	22	22	22	22
ALSANDS								11	22	22	22	22	22	22	22	22	22	22	22	22	22
POTENTIAL PROJECT #1													10	20	20	20	20	20	20	20	20
" #2															10	20	20	20	20	20	20
" #3																	10	20	20	20	20
" #4																			10	20	20
" #5																					10
TOTAL (COMMERCIAL)	18	20	26	29	29	29	30	51	76	83	83	83	93	103	113	123	133	143	153	163	173

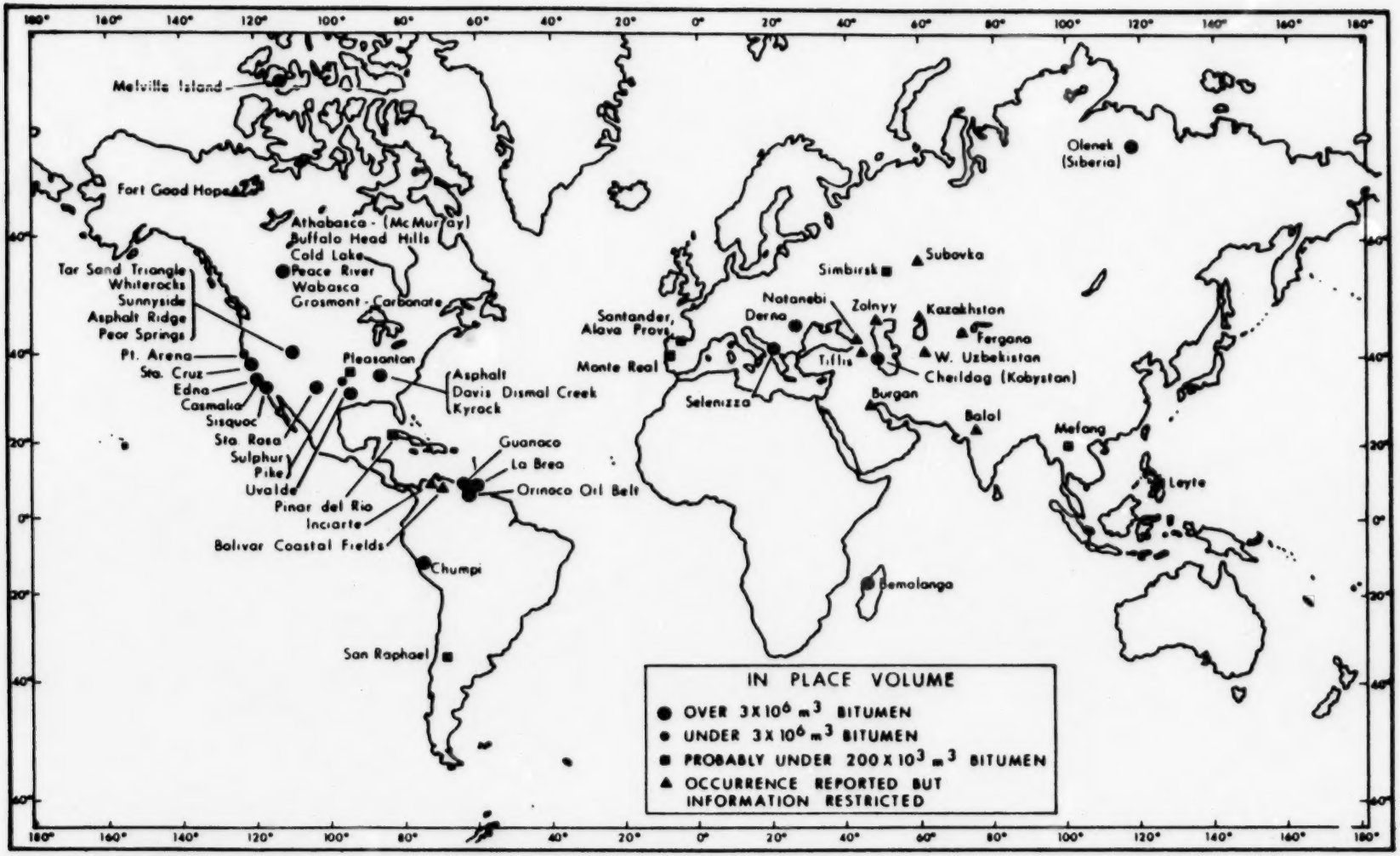
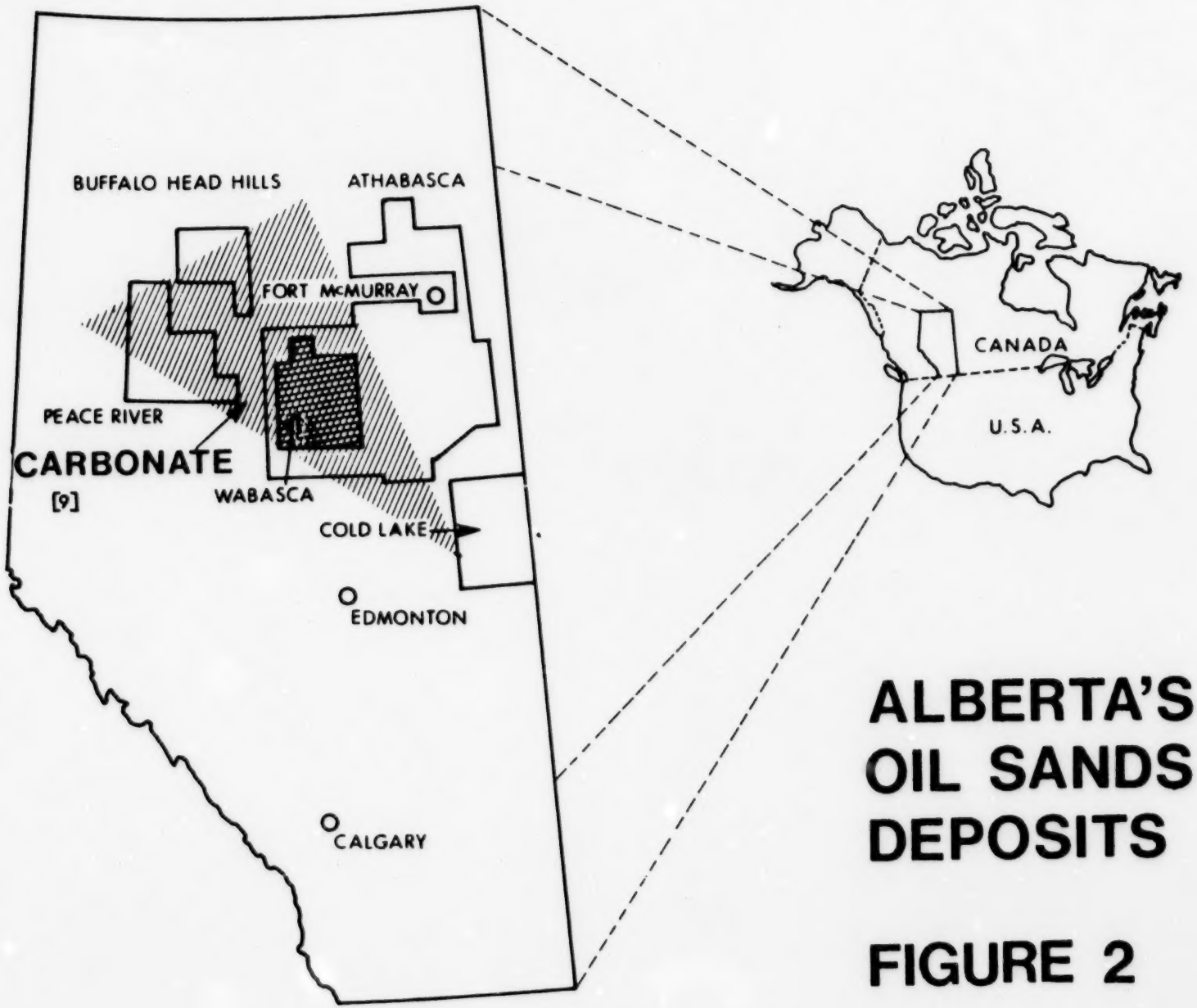


FIGURE 1 OIL SANDS OF THE WORLD - LOCATION MAP (AFTER PHIZACKERLEY AND SCOTT)



ALBERTA'S OIL SANDS DEPOSITS

FIGURE 2

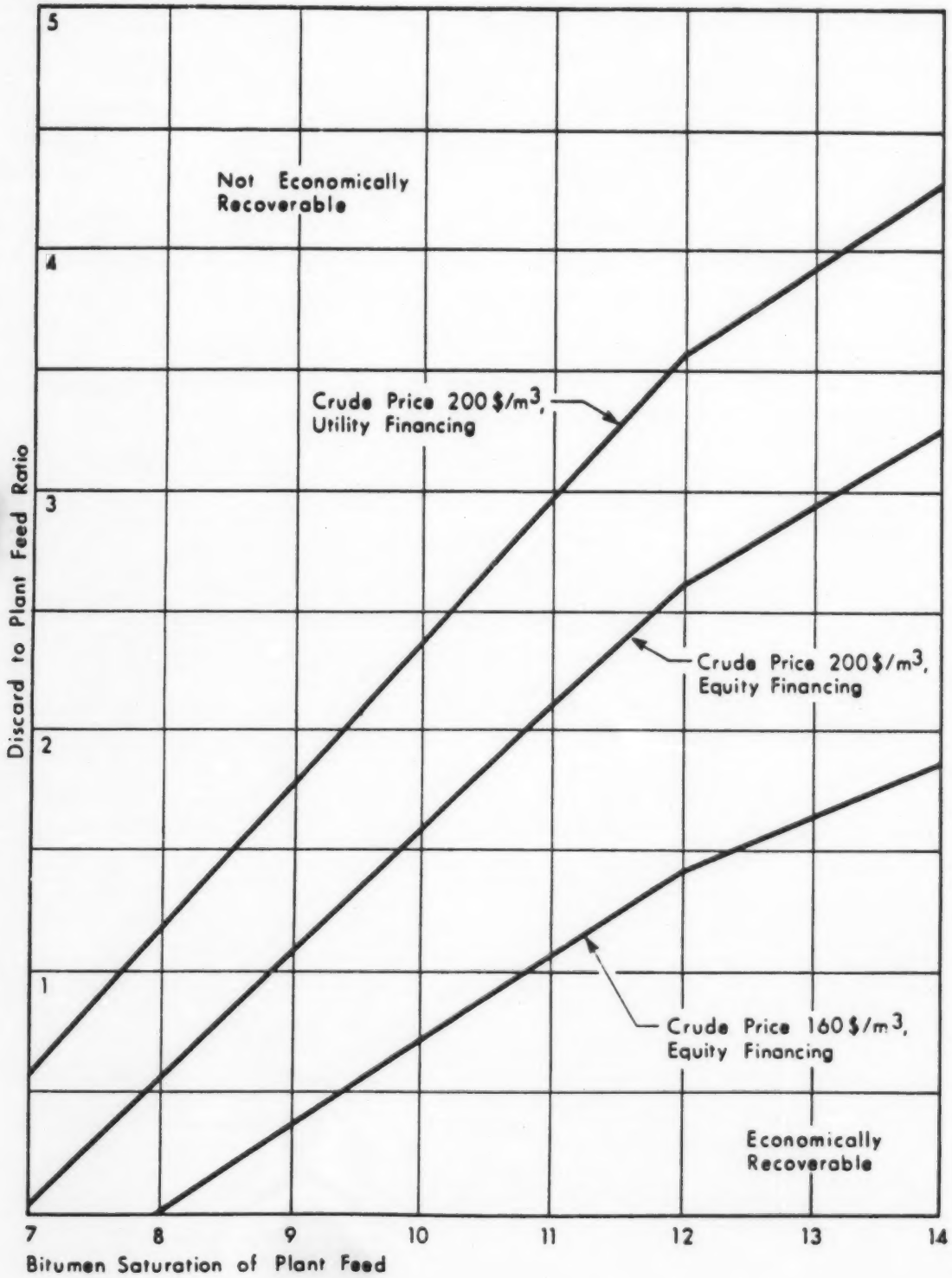


FIGURE 3
ECONOMIC STRIPPING RATIO .

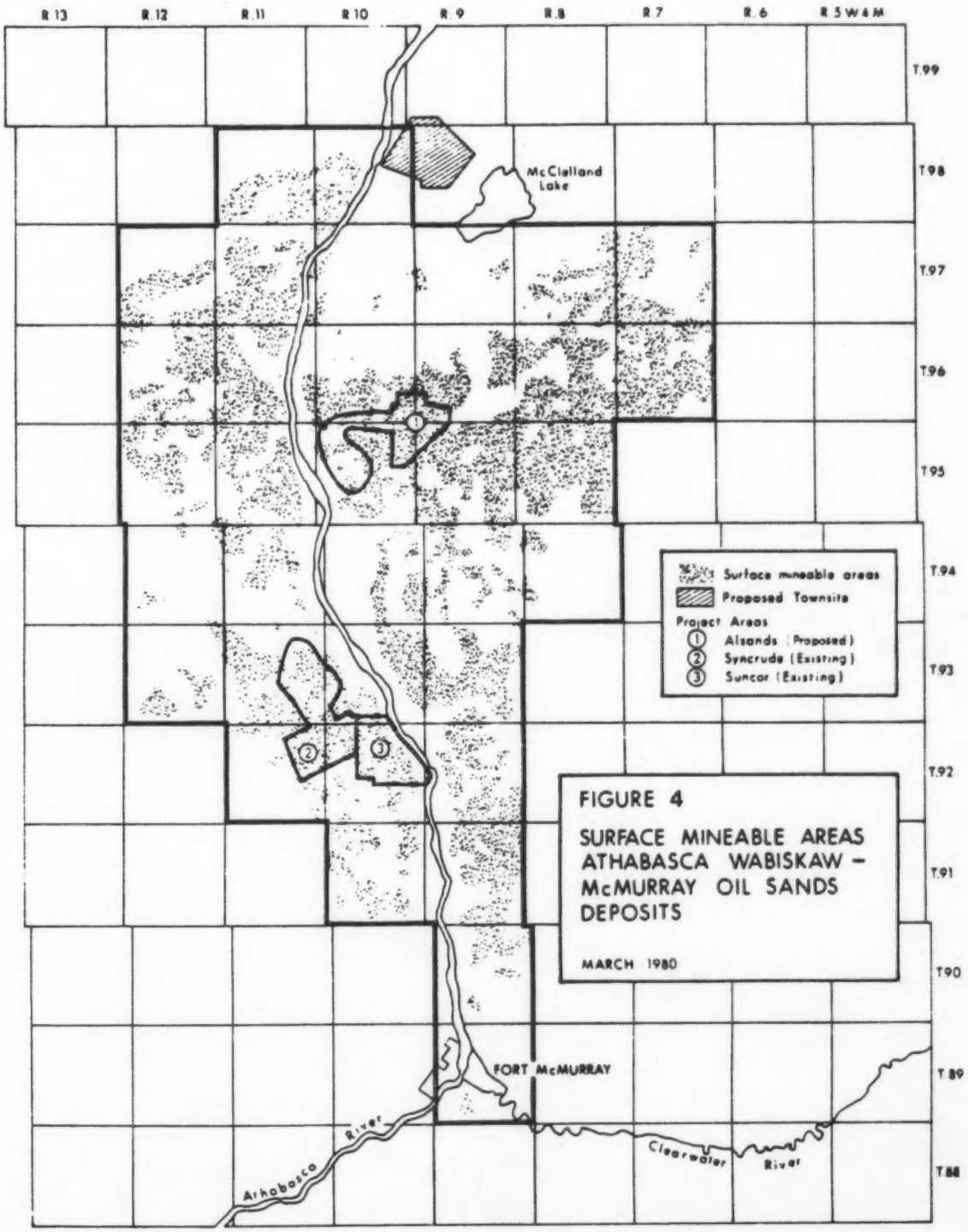
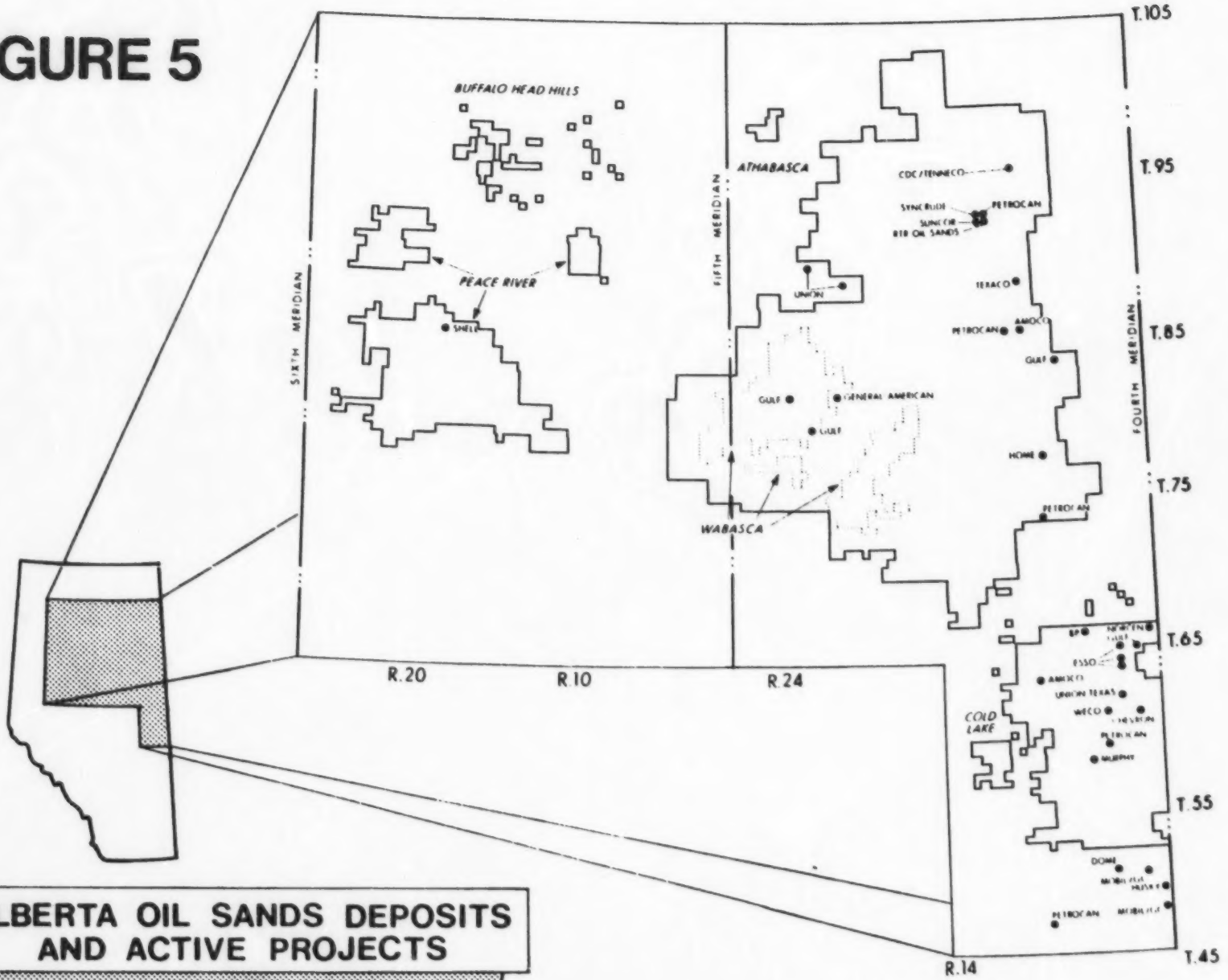

R.13
R.12
R.11
R.10
R.9
R.8
R.7
R.6
R.5W4M
T.99
T.98
T.97
T.96
T.95
T.94
T.93
T.92
T.91
T.90
T.89
T.88
McClelland Lake
Surface mineable areas
Proposed Townsite
Project Areas
1 Alsands (Proposed)
2 Syncrude (Existing)
3 Suncor (Existing)
FIGURE 4
SURFACE MINEABLE AREAS ATHABASCA WABISKAW – McMURRAY OIL SANDS DEPOSITS
MARCH 1980
FORT McMURRAY
Athabasca River
Clearwater River

FIGURE 5



ALBERTA OIL SANDS DEPOSITS AND ACTIVE PROJECTS

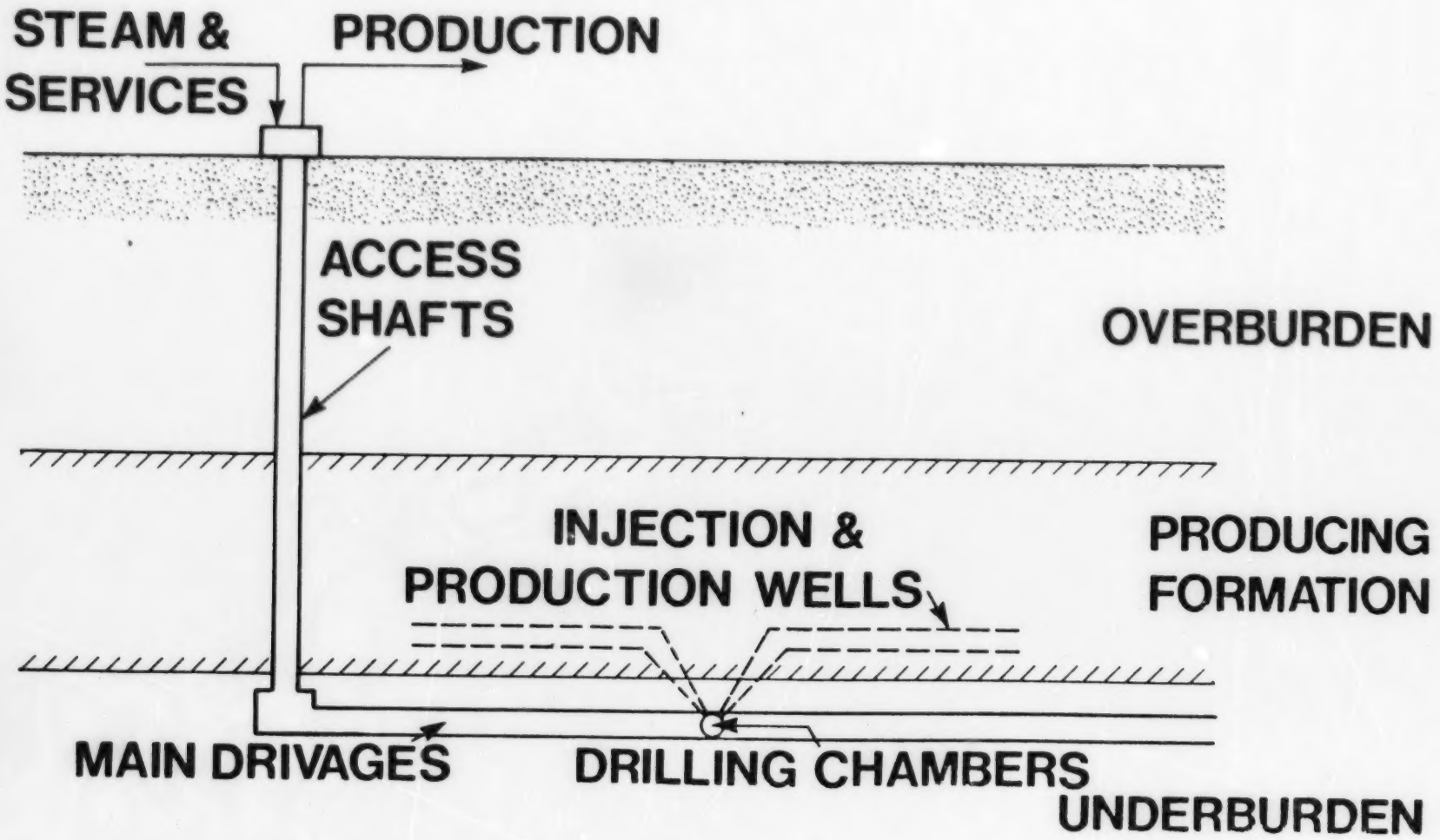


FIGURE 6 MAISP SCHEMATIC

AFTER HASTON (21)